1999 Annual Report

Bonterra Energy Corp.

Corporate Profile

Bonterra Energy Corp. (Canadian Venture Exchange - BON) is a junior resource company that explores for, develops and produces oil and natural gas in the Provinces of Alberta and Saskatchewan. The Company was incorporated on February 17, 1998, and finalized its initial public offering on July 28, 1998.

The Company's business strategy is to strive to maximize shareholder value by applying long-term growth objectives. The Company's primary objective is to combine its oil and gas production technical strengths with planned business strategies to generate above average results and returns for our shareholders.

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Bonterra Energy Corp.

Notice of Annual Meeting

The Annual Meeting of Shareholders will be held on Monday, June 12, 2000, in the Bonavista Room at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 10:30 a.m. (Calgary time).

Highlights

	1999	1998
Financial ($000, except $ per share)		
Revenue – oil and gas (net of royalties)	$13,214	$ 2,131
Cash Flow from Operations	3,829	395
Per Share Fully Diluted	0.11	0.05
Net Earnings (Loss)	676	(201)
Per Share Fully Diluted	0.02	(0.03)
Capital Expenditures and Acquisitions	254	20,791
Outstanding Debt	15,048	17,884
Shareholders' Equity	3,286	2,603
Shares Outstanding (weighted average) (000's)	31,542	7,535
Operations		
Oil and Liquids (barrels per day)	1,576	397
Average Price ($ per barrel)	$23.46	$16.70
Natural Gas (MCF per day)	821	164
Average Price ($ per MCF)	$ 2.80	$ 2.54
Reserves (proved producing)		
Oil and Liquids (barrels in 000's)	7,674	7,329
Natural Gas (MCF in 000's)	3,149	4,233
Key Ratios		
Rate of Earnings on Capital Employed	21.9%	(6.5%)
Rate of Cash Flow on Capital Employed	124.1%	12.8%
Rate of Earnings on Shareholders' Equity	20.6%	(7.7%)
Rate of Cash Flow on Shareholders' Equity	116.5%	15.2%

The Company made a major oil and gas producing property acquisition in 1998. The effective date for this acquisition is November 1, 1998. On July 28, 1999, the Company split its common shares and each shareholder received an additional share for each share held on the record date.

Report to Shareholders

The Company is pleased to report its operational and financial results for its first full year of operation. Bonterra has made gigantic strides considering it has received only $3,085,000 in equity financing. During its first full year of operation the Company had cash flow from operations of $3,829,000 representing more than 100 percent cash flow return on equity. Projections for 2000 are for cash flow to double without any further equity issues. By the end of 2000 we project that bank debt will be substantially reduced. Debt, of course, would increase if the Company is able to make a major producing property acquisition or participates in a major drilling program. The Company has credit arrangements in place to proceed with aggressive expansion if an opportunity is available.

Operations

Bonterra operates in three areas. The Pembina area of Alberta accounts for approximately two-thirds of its production. Approximately one-quarter of its production is from the Dodsland area of southwest Saskatchewan, and the remaining eight percent is from the Pinto area of southeast Saskatchewan.

Oil production from these three areas is primarily light sweet gravity crude that accounts for approximately 85 percent of revenue. Natural gas and liquids production from these three areas accounts for the remaining 15 percent. All three properties have long-term reserves and the Company has a long production life index of 13.3 years for crude oil and 10.5 years for natural gas and liquids. These indexes are substantially higher than industry average in the Western Canadian basin.

Financial

A major acquisition in November, 1998, resulted in the Company having to borrow approximately $18,000,000. In 1999 the Company focus was mainly on debt reduction and reducing operating costs rather than on expenditures to increase production. Bonterra's debt to cash flow ratio was high and needed to be rectified. Total debt has been significantly reduced and by the end of quarter two, 2000, it should be approximately one year's cash flow, a very acceptable industry level. The Company is now able to make expenditures to increase production.

Oil prices during 1999 had large fluctuations. The first quarter prices were approximately $13.00 U.S. for West Texas Intermediate quality crude. For the fourth quarter of 1999, prices were approximately $25.00 U.S. and brought the Company's yearly average to $23.87 Cdn. after adjusting for hedging losses. The large debt position made it more critical to ensure certain levels of cash flow in 1999, therefore, the Company had a greater need to enter into hedging contracts. Lower debt levels in 2000 will allow the Company to reduce its hedging programs.

(L to R) Jerry Jeffcott, Production Supervisor, Carl Jonsson, Director, Steve Safronovich, Vice President, Operations.

Specific areas of growth in 1999 follow:

- A cash flow increase to $3,829,000 from $395,000 in 1998;
- Net earnings of $676,000 compared to a 1998 loss of $201,000;
- Production increase on a BOE basis to 1,658 BOE/day from 413 BOE/day in 1998.

Outlook

The first objective in 2000 is for the Company to develop its natural gas properties. Most of this development will commence during the summer months. Management and Directors will also be pursuing further acquisitions of producing and non-producing oil and gas properties and potential mergers with, or acquisitions of, existing oil and gas companies.

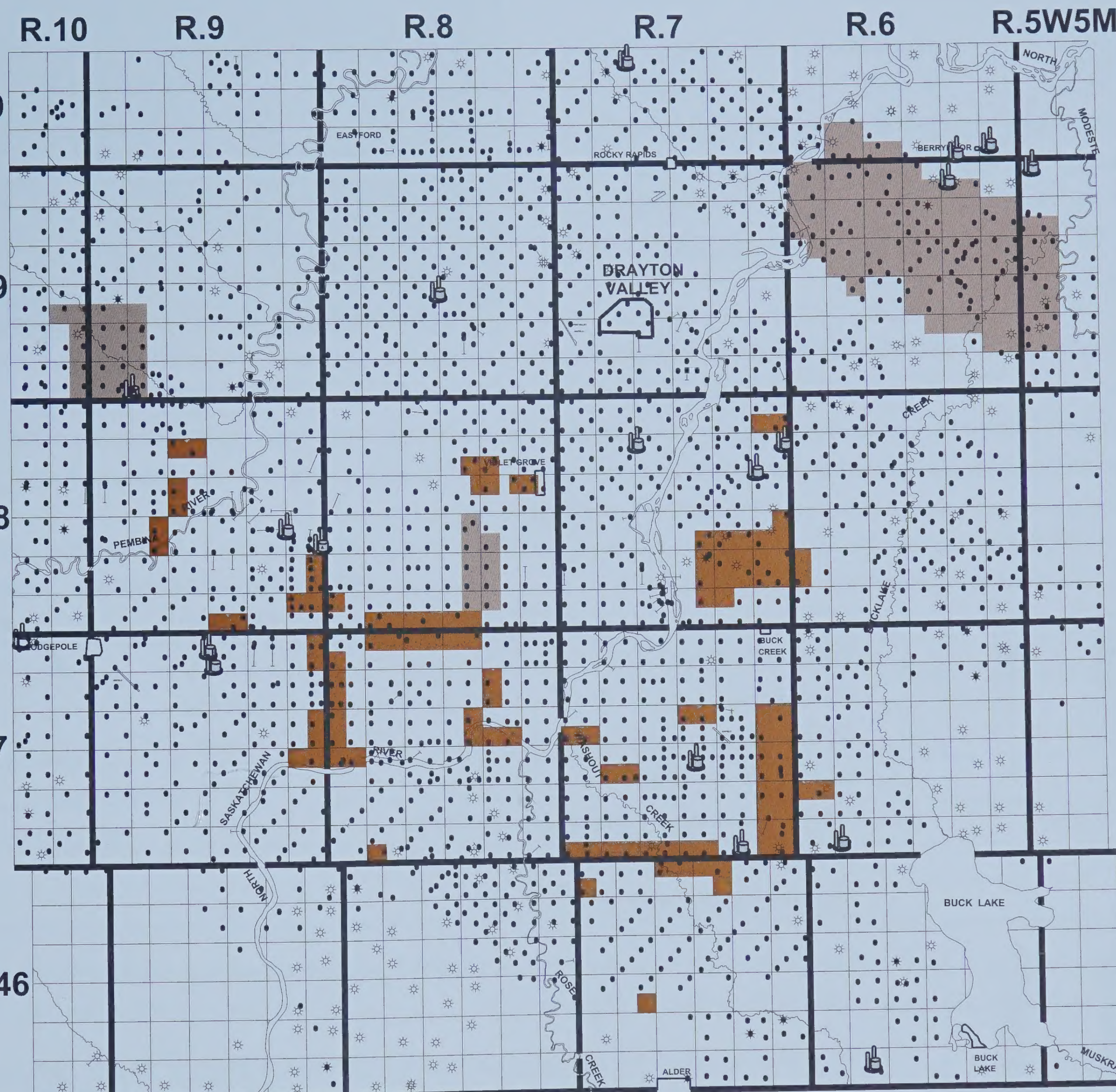
Corporate

The Company regrets to report the death of Director, Senator R. James Balfour in December, 1999. Senator Balfour was one of the Company's founding Board members and provided a great amount of assistance in establishing philosophy, policy, and direction. His input and advice will be missed.

The Board of Directors wish to thank its staff for the effort and commitment during the Company's first full year of operation and to its shareholders for the support and loyalty that has been provided in 1999.

Submitted on behalf of the Board of Directors,

George F. Fink
President and Director



Bonterra
Energy Corp.

PEMBINA FIELD

BONTERRA OPERATED LANDS
BONTERRA NON-OPERATED LANDS
PRODUCING GAS WELL
PRODUCING OIL WELL
GAS PLANTS

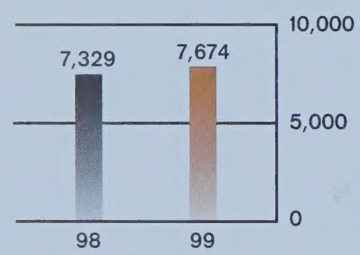
Review of Operations

Reserves

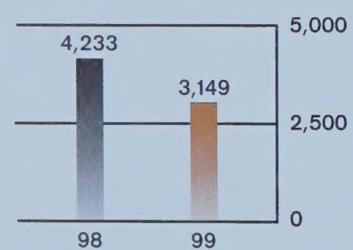
The Company engaged an independent engineering firm to prepare the following reserve evaluation. The effective date for this evaluation is July 1, 1999. Management adjusted the engineering report for production from July 1, to December 31, 1999.

(L to R) Gary Drummond, Director, Randy Jarock, Operations Manager and Vice President, Acquisitions.

The reserves are located in the Provinces of Alberta and Saskatchewan. The majority of the Company's production is comprised of light sweet crude, which results in higher oil prices, and better marketing opportunities. The Company's main oil producing areas are located in the Pembina area of Alberta and Dodsland area of Saskatchewan. Oil and natural gas proven reserve estimates at December 31, 1999, before royalties, are as follows:



Oil and NGL Reserves (Proven) (MBbls)



Natural Gas Reserves (Proven) (MMCF)

	Crude Oil and Liquids (MBbls)	Natural Gas (MMCF)
January 1, 1999	7,329	4,233
Production	(575)	(299)
Evaluation adjustments to reserves	920	(785)
December 31, 1999	7,674	3,149
Life index (years) - December 31, 1999	13.3	10.5
Life index (years) - December 31, 1998 (based on year end production)	11.8	13.8

The above reserve numbers represent proved producing crude oil, liquids and natural gas. No probable reserves have been included.

The reserve values in the following table, "Estimated Present Worth of Reserves", are based upon proved producing reserve estimates at December 31, 1999, calculated as described above.

Estimated Present Worth of Proven Producing Reserves

		Discounted at		
(Millions of dollars)	0%	10%	15%	20%
Proved producing at December 31, 1999	120.8	52.2	40.7	33.5
Proved producing at December 31, 1998	62.9	32.7	27.3	22.4

Commodity prices used in the above calculations of reserves are as follows:

Year	Edmonton Par Price (Cdn $ per barrel)	AECO Price (Cdn $ per MCF)	Propane (Cdn $ per barrel)	Butane (Cdn $ per barrel)	Pentane (Cdn. $ per barrel)
2000	27.51	2.93	14.86	15.99	28.17
2001	27.13	2.83	14.66	15.77	27.78
2002	27.15	2.81	14.67	15.78	27.81
2003	27.56	2.85	14.89	16.02	28.23
2004	27.98	2.89	15.12	16.27	28.66
2005	28.41	2.94	15.35	16.51	29.09

Prices escalate at 1.5% per year thereafter.

Production

The following table provides a summary of production volumes from our main producing areas. Figures for 1998 comparative purposes represent average production rates from November 1, 1998 (major acquisition date) to December 31, 1998.

	Oil and NGL (Bbls/day) 1999	Natural Gas (MCF/day) 1999	Oil and NGL (Bbls/day) 1998	Natural Gas (MCF/day) 1998
Pembina, Alberta	1,062	458	1,243	525
Dodsland, Saskatchewan	446	306	380	232
Pinto, Saskatchewan	68	57	72	83
	1,576	821	1,695	840

In 1999 the Company's focus was mainly on debt reduction and reducing operating costs rather than on expenditures to increase production. Total debt has now been significantly reduced and our 2000 focus will include production increases along with debt reduction and cost control.

Land Holdings

The Company's holdings of petroleum and natural gas leases and rights are as follows:

	1999		1998	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	34,114	26,160	34,114	26,160
Saskatchewan	29,630	17,768	29,630	17,768
	63,744	43,928	63,744	43,928

Acquisitions and Drilling

During 1998, the Company's acquisitions of oil and natural gas properties as outlined above resulted in total acquisition costs averaging $2.60 per barrel of oil equivalent of proved producing reserves.

Capital costs incurred in 1999 were entirely related to capital maintenance programs on existing properties.

Property Discussions

General

As previously disclosed, when Bonterra made its major producing property acquisition, oil prices were in the $11.00 to $12.00 U.S. range. In attempting to control costs as much as possible during the low price period, the Company decided not to do workovers or repair marginal producing wells. This approach was necessary considering the circumstances; however, it did result in reductions in production. Higher oil prices during the latter part of 1999 once again made these wells economic and rework and repair programs were initiated. The Company's average production in 1999 was 1,658 BOE per day. The present production from these properties is approximately 1,750 BOE per day. The Company's 1999 operating costs of $12.73 per BOE were approximately 20 percent lower than costs incurred by the previous owner ($15.40 per BOE) for the 12-month period prior to Bonterra's acquisition. It is anticipated that these costs will be further reduced on a BOE basis in 2000.

Pembina Area

Most of the production from this area is light, sweet gravity crude from the Cardium sandstone formation from a depth of approximately 5,000 feet. To maintain formation pressure, water injection commenced in the 1960's and continues, resulting in low production declines. The properties contain 101 gross (84.7 net) operated producing wells with an 83.9 percent average working interest, and 189 gross (32.1 net) non-operated producing wells with an approximate 17 percent average working interest. Bonterra operates approximately 75 percent of the production from this area. The Company projects little or no production declines from this area for 2000.

Dodsland Area, Southwest Saskatchewan

The Dodsland properties produce light sweet gravity oil and solution gas from the Viking sandstone formation at a depth of approximately 2,300 feet. The properties contain approximately 400 gross (350 net) operated oil wells with an 88 percent average working interest. Average daily production from this area is approximately 470 BOE per day (net to Bonterra). Production from this area has low decline rates and a long economic life. Due to low average daily production of about 1.3 BOE per day per well, the operating costs per BOE of approximately $21.00 are quite high. At existing prices of $30.00 to $35.00 Cdn., the cash flow margin per BOE is still substantial. In 2000 the Company will be assessing this property on a well-by-well basis and will transfer the uneconomic wells to a previous owner (as per our present agreement). This process will reduce the operating costs and increase cash flow for the Dodsland area.

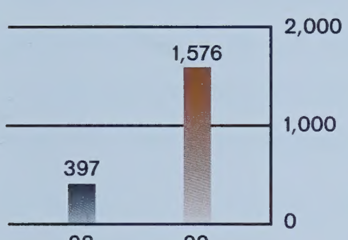
Pinto Area, Southeast Saskatchewan

The Pinto property produces slightly sour gravity oil and solution gas from the Midale formation. The Company has an average working interest of approximately 95 percent. During the fourth quarter of 1999, Bonterra initiated rework programs on producing and shut-in wells resulting in a production increase of approximately 40 percent. Production from this formation has very low decline rates.

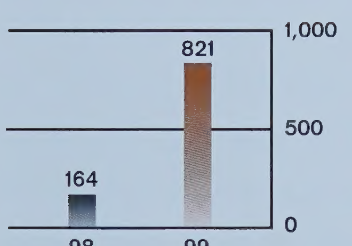
Management's Discussion and Analysis

This report is a review of the operations, current financial position, and outlook for the Company and should be read in conjunction with the audited financial statements for the fiscal year ended December 31, 1999, together with the notes related thereto.

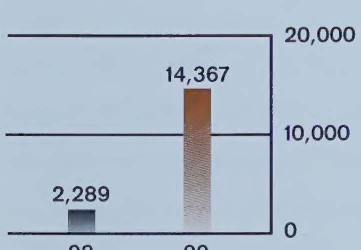
The Company was incorporated on February 17, 1998, and commenced trading on The Canadian Venture Exchange on July 28, 1998, with its initial public offering. The Company acquired a nominal amount of production effective March 1, 1998, followed by a major $19,675,000 acquisition effective November 1, 1998. Throughout 1999, the Company concentrated on reducing operating costs and paying down debt. For 2000, the Company's focus is on an assessment of existing production to determine if it can be increased, a study to determine if there are exploration and development opportunities for further drilling in existing production zones or undrilled zones, continued reduction in operating costs and a further reduction of debt. Our efforts to date have had a positive effect in 1999 and should have an even greater affect in 2000 and subsequent years.



Oil and NGL Production (Bbls/day)



Natural Gas Production (MCF/day)



Gross Revenues ($000)

Production

The Company's average production of oil and natural gas liquids increased by 297 percent to 1,576 barrels per day in 1999 from 397 barrels per day in 1998. In addition, the Company's natural gas production increased by 401 percent to 821 MCF per day in 1999 from 164 MCF per day in 1998. The increases were the result of our major acquisition on November 1, 1998. In December 1999, the Company reactivated 8 wells in the Pinto area of Saskatchewan. It is projected that average production from this area will increase from 75 BOE per day to 125 BOE per day. With the continuing high oil and natural gas prices, the Company continues to review wells in the Pembina area for additional oil and natural gas production opportunities.

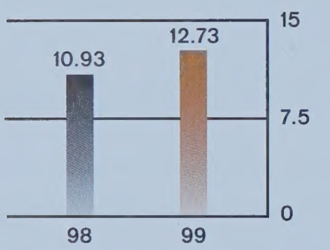
Revenue

Gross revenue from petroleum and natural gas sales for 1999 was $14,332,776 compared to $2,240,452 for the 1998 fiscal period. In 1999 the average price received for crude oil was $23.87 (1998 - $16.86) per barrel, $2.80 (1998 - $2.54) per MCF of natural gas, and $14.90 (1998 - $10.07) per barrel of natural gas liquids. Due to the high level of debt incurred with the property acquisition in 1998, the Company entered into forward sales agreements for up to 40 percent of its oil production in 1999 to ensure a certain level of cash flow. As of December 31, 1999, Bonterra has forward sold a total of 700 barrels per day for the period January 1, 2000 to April 30, 2000 at approximately $30.30 Canadian per barrel, and 400 barrels per day for the period May 1, 2000 to May 31, 2000 at $22.05 U.S. per barrel.

Royalties

Royalties paid by the Company consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During 1999, the Company paid $950,372 in Crown royalties and $168,167 in freehold royalties, gross overriding royalties and net carried interests. This compares to 1998 payments of $95,256 and $13,869 respectively. The majority of the Company's wells are low productivity wells and therefore have low Crown royalty rates. The Company's average Crown royalty rate is approximately 6 percent and approximately 1 percent for other royalties.

The Company is not eligible for any Alberta Crown Royalty rebates, as the properties were previously owned by above limit corporations.

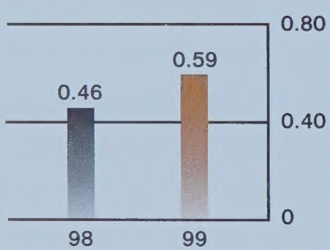


Production Costs
($ Per BOE)

Production Costs

Production costs increased to $7,705,479 in 1999 from $1,436,287 during the 1998 fiscal period. The increase was entirely due to the Company making its major producing property acquisition effective November 1, 1998, and therefore production costs in 1998 were primarily for a two month period compared to a full year for 1999. On a BOE basis operating costs for 1999 were $12.73. Most of the Company's production is from low productivity wells, and the BOE costs of $12.73 is very much in line with industry standards for this type of production.

The Company's 1999 costs were approximately twenty percent lower than costs incurred by the previous owner ($15.40 per BOE) for the 12 month period prior to Bonterra's acquisition. It is anticipated that these costs will be further reduced on a BOE basis in 2000.



General and Administrative
($ Per BOE)

General and Administrative Expenses

General and administrative expenses increased to $356,123 in 1999 from $60,666 in 1998. On a BOE basis, general and administrative expenses increased by 28.3 percent to $0.59 in 1999 from $0.46 in 1998. The increase was primarily the result of additional management services and production accounting costs associated with the operation of the petroleum and natural gas properties acquired in 1998. These expenses on a BOE basis are less than 50 percent of industry average.

The Company has entered into a management agreement with Comstate Resources Ltd. (Comstate) to provide field operations, management and general office services. Fees charged for field operations are charged on a per well basis. A flat fee of $5,000 per month is charged for management and general office services. Fees associated with well operations are charged to production costs as incurred. The Company has not capitalized any general and administrative expenses in either 1999 or 1998.

Interest Expense

Interest expense for the fiscal year ending December 31, 1999, totaled $1,144,121 compared to $249,978 for the 1998 fiscal period. At December 31, 1999, the Company had outstanding loans to Comstate ($6,500,000) and to its principal banker ($8,548,436). Interest rate charges during 1999 on the outstanding debt to Comstate were Canadian chartered bank prime plus one percent, and to its principal banker, Canadian chartered bank prime plus one half of one percent.

Effective January 1, 2000, the interest rate charged on the Comstate outstanding loan was reduced to Canadian chartered bank prime plus one half percent. In addition, effective November 1, 1999 the rate charged by its principal banker was reduced to Canadian chartered bank prime plus one quarter. The Company has the ability to use Bankers Acceptances (BA's) as part of its loan facility. Interest charges on BA's are generally one half percent lower than that charged on the general loan account. The interest rate reductions were made because of reduced risk.

Depletion, Depreciation, Future Site Restoration and Dry Hole Costs

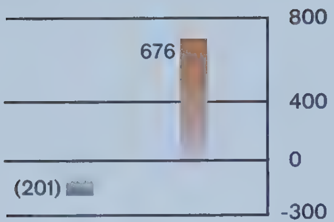
The Company depletes its oil and natural gas intangible assets using the unit of production basis by field. For tangible assets such as well equipment, a life span of ten years is estimated and the related tangible costs are depreciated at one tenth of original cost per year. Provisions are made for future site restoration based on management's estimation of abandonment requirements using current costs and amortized on a unit of production basis by field.

For the fiscal year ending December 31, 1999, the Company expensed $2,614,005 for the above-described items. This compares to $425,981 expensed in 1998. For the majority of the assets, which were acquired effective November 1, 1998, only two months of depletion, depreciation and amortization of future site restoration were expensed in 1998.

The Company follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. During 1999, the Company did not participate in drilling any wells. In the 1998 fiscal period, one exploration well (.33 net) was unsuccessful and therefore the costs of $276,834 associated with the land acquisition and drilling were charged to operations in 1998.

Income Taxes

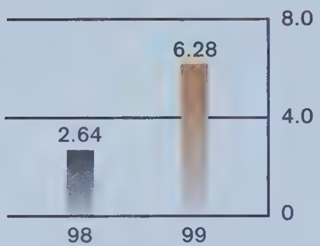
Current taxes of $213,820 (1998 - $38,000) consist entirely of taxes related to federal large corporation tax and the Saskatchewan resource surcharge. The Company's primary tax pool is Canadian oil and gas property expense that can be written off at an annual rate of 10 percent on a declining balance basis. The Company was able to shelter its 1999 income through maximizing 1998 deductions available.



Net Earnings (Loss)
($000)

Net Earnings (Loss)

During 1999 the Company reported net earnings of $675,601 or $0.02 per share. This compares to a net loss of $200,942 during its fiscal period ending December 31, 1998. The Company's low acquisition costs of $2.60 per BOE for its proven reserves, continued reduction of operating costs, and the current high oil and natural gas prices, should assist in providing substantial future earnings.



Cash Netbacks
($ Per BOE)

Cash Flow From Operations

Cash flow from operations for the fiscal period ending December 31, 1999, increased 870 percent to $3,829,103 ($0.11 per fully diluted average outstanding share) compared to $394,953 ($0.05 per fully diluted average outstanding share) in 1998. Continued operating cost reductions, projected continued high oil and natural gas prices, and increased production should substantially increase the Company's 2000 cash flow.

Cash Netback

The following table illustrates the Company's cash netback:

$ per BOE	1999	1998
Production volumes (BOE)	605,084	131,388
Gross production revenue	$ 23.69	$ 17.05
Royalties	(1.85)	(0.83)
Field operating	(12.73)	(10.93)
Field netback	9.11	5.29
General and administrative	(0.59)	(0.46)
Interest	(1.89)	(1.90)
Taxes	(0.35)	(0.29)
Cash netback	$ 6.28	$ 2.64

Liquidity and Capital Resources

At December 31, 1999, the Company had bank debt of $8,548,436. Bonterra's credit facility at year-end consisted of a revolving line of credit of $10,000,000 and carried an interest rate of one quarter percent above Canadian chartered bank prime. The credit facility allows for borrowings by means of Bankers Acceptances (BA's). The effective interest rates of BA's are generally half a percentage point lower than that available under the normal credit facility. The Company attempts to maximize the amount of its credit facility used by financing with BA's to reduce overall interest costs. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Company's assets and a general security agreement.

The Company has an outstanding loan amount as of December 31, 1999 of $6,500,000 to Comstate Resources Ltd. The loan was acquired to assist in financing the Company's November 1, 1998 acquisition. Repayments of the loan as well as interest payments are limited to Company cash flow as determined by accounting principles generally accepted in Canada. As of March 31, 2000, Bonterra has repaid $2,500,000 of the outstanding loan to Comstate and anticipates full repayment by September 30, 2000, subject to continued strength in crude oil prices. Comstate has not taken specific security for the loan but reserves the right to obtain secondary charges over Bonterra's oil and gas properties. Due to the secondary nature of the loan, the interest rate charged by Comstate is Canadian chartered bank prime plus one half percent compounded quarterly.

At December 31, 1999, the Company has 3,091,000 stock options issued under its Stock Option Plan. The options which are available on a three year schedule must be exercised on or before May 1, 2003. The stock options range in price from $0.10 to $0.50 (the trading price on the day the options were issued) with an average exercise price of $0.128 per share.

Business Prospects, Risks, and Outlooks

The resource industry operates with a great deal of risk. The most significant risks may come from oil and natural gas price swings, the uncertainty of finding new reserves from drilling programs or acquisitions, competition within the industry, and increasing environmental controls and regulations.

The prices received for crude oil are established by world market forces and for natural gas by forces within North America. Fluctuations in pricing can have extremely positive or negative effects on the Company's cash flow or in the value of its producing and non-producing oil and natural gas properties.

Bonterra presently attempts to minimize these risks by pursuing both oil and natural gas activities. The Company may sometimes elect to protect against price fluctuation by using commodity hedging. The Company operates its oil and natural gas interests in areas which have long life reserves, and where it has the technical expertise to enhance production, control operating costs and to increase margins of profit.

Sensitivity Analysis

Sensitivity analysis as estimated for 2000 follows:

	Cash Flow	Cash Flow Per Share
U.S. $1.00 per barrel	$370,000	$ 0.011
Canadian $0.10 per MCF	$ 13,000	$ 0.001
Change of Canadian $0.01/U.S. $ exchange rate	$ 114,000	$0.003

Management's Responsibility for Financial Statements

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of the statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and to facilitate in the preparation of relevant and timely information.

Deloitte & Touche LLP has been appointed by the shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditors' report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

Garth Schultz

Garth E. Schultz
Vice President, Finance

Auditors' Report

To the Shareholders of Bonterra Energy Corp.:

We have audited the balance sheets of Bonterra Energy Corp. as at December 31, 1999 and 1998 and the statements of earnings (loss) and retained earnings and cash flow for the periods then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as, evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 1999 and 1998, and the results of its operations and cash flow for the periods then ended in accordance with accounting principles generally accepted in Canada .

Deloitte & Touche LLP

Calgary, Alberta
March 31, 2000

Chartered Accountants

Balance Sheets

As at December 31	1999	1998
Assets		
Current		
Accounts receivable	$ 2,010,476	$ 800,571
Inventories	602,161	281,541
Prepaid expenses	158,087	–
	2,770,724	1,082,112
Abandonment deposit (Note 3)	1,213,378	–
Future income tax asset (Note 7)	–	371,833
Property and equipment (Note 4)		
Property and equipment	20,124,728	20,034,595
Accumulated depletion and depreciation	(1,878,928)	(289,952)
Net property and equipment	18,245,800	19,744,643
	$22,229,902	$ 21,198,588
Liabilities		
Current		
Bank indebtedness	$ 589,013	$ 2,225
Accounts payable and accrued liabilities	2,141,698	574,066
Current portion of long term debt (Note 5)	6,500,000	1,600,000
	9,230,711	2,176,291
Long term debt (Note 5)	8,548,436	16,283,758
Future income tax liability (Note 7)	167,663	–
Future site restoration	997,281	136,029
	18,944,091	18,596,078
Shareholders' Equity		
Share capital (Note 6)	3,085,429	3,077,729
Excess of cost of petroleum and natural gas properties over related net book value of vendor corporation (Note 4)	(274,277)	(274,277)
Retained earnings (deficit)	474,659	(200,942)
	3,285,811	2,602,510
	$22,229,902	$ 21,198,588

Statements of Earnings (Loss) and Retained Earnings

Periods ended December 31 (Note 1)	1999	1998
Revenue		
Oil and gas sales, net of royalties of $1,118,539 (1998 - $109,299)	$13,214,237	$ 2,131,153
Production costs	(7,705,479)	(1,436,287)
Interest and other	34,409	48,731
	5,543,167	743,597
Expenses		
General and administrative	356,123	60,666
Interest on long term debt	1,144,121	249,978
	1,500,244	310,644
Cash flow from operations before current income taxes	4,042,923	432,953
Depletion, depreciation and future site restoration	2,614,005	425,981
Dry holes	–	276,834
	2,614,005	702,815
Earnings (loss) before income taxes	1,428,918	(269,862)
Income taxes (recovery) (Note 7)		
Current	213,820	38,000
Future	539,497	(106,920)
	753,317	(68,920)
Net earnings (loss) for the period	$ 675,601	$ (200,942)
Deficit, beginning of period	(200,942)	–
Retained earning (deficit), end of period	$ 474,659	$ (200,942)
Net earnings (loss) per share	$ 0.02	$ (0.03)

Statements of Cash Flow

Periods ended December 31 (Note 1)	1999	1998
Operating Activities		
Net earnings (loss) for the period	$ 675,601	$ (200,942)
Items not affecting cash		
Depletion, depreciation and future site restoration	2,614,005	425,981
Dry holes	–	276,834
Future income taxes	539,497	(106,920)
Cash flow from operations	3,829,103	394,953
Change in non-cash operating working capital items	(120,980)	(508,044)
	3,708,123	(113,091)
Financing Activities		
Increase (decrease) in long term debt	(2,835,322)	17,883,757
Issuance of common shares	7,700	3,151,191
Share issue costs	–	(133,566)
	(2,827,622)	20,901,382
Investing Activities		
Property and equipment expenditures	(253,911)	(20,790,516)
Abandonment deposit (Note 3)	(1,213,378)	–
	(1,467,289)	(20,790,516)
Net cash outflow	(586,788)	(2,225)
Bank indebtedness, beginning of period	(2,225)	–
Bank indebtedness, end of period	$ (589,013)	$ (2,225)

Notes to the Financial Statements

Periods ended December 31, 1999 and 1998 (Note 1)

1. INCORPORATION

The Company was incorporated in the Province of Alberta on February 17, 1998. The comparative financial statements represent the operations of the Company from this date to December 31, 1998.

2. SIGNIFICANT ACCOUNTING POLICIES

Property and Equipment

Petroleum and Natural Gas Properties and Related Equipment

The Company follows the successful efforts method of accounting for petroleum and natural gas properties and related equipment. Costs of acquiring unproved properties are capitalized and amortized on a straight-line basis over the lives of the related leases. When property is found to contain proved reserves as determined by Company engineers, the related net book value is depleted on the unit-of-production basis, calculated by field. The costs of dry holes and abandoned properties are charged to operations. Geological costs, lease rentals and carrying costs are charged to income as incurred. Costs of drilling exploratory and development wells that result in additions to proved reserves are capitalized and depleted on the unit-of-production basis. Tangible equipment is depreciated on a straight-line basis over ten years.

Furniture, Fixtures and Office Equipment

Other assets are recorded at cost and depreciated over a three to ten year period representing their estimated useful lives.

Income Taxes

The Company follows the tax payable method of accounting under which the income tax provision is based on the temporary differences in the accounts calculated using income tax rates expected to apply in the year in which the temporary differences will reverse.

Future Site Restoration

The Company provides for future site restoration and abandonment costs over the estimated production life of its property and equipment. Estimates of these amounts are based on the anticipated method and extent of site restoration using current costs and in accordance with existing legislation and industry practice. The annual charge is included with depletion, depreciation and future site restoration.

Stock-based Compensation Plan

The Company has a stock-based compensation plan as described in Note 6. No compensation expense is recognized for the plan when stock or stock options are issued to service providers. Any consideration paid by service providers on exercise of stock options is credited to share capital.

Joint Interest Operations

Significant portions of the Company's oil and gas operations are conducted with other parties and accordingly the financial statements reflect only the Company's proportionate interest in such activities.

Inventories

Inventories consist of products that are valued at current market price as of December 31.

Net Earnings (Loss) Per Common Share

Net earnings (loss) per common share is calculated using the weighted average number of common shares outstanding during the period which was 31,542,239 (1998 - 7,535,279). The exercise of outstanding stock options would have no dilutive effect on net earnings (loss) per common share.

3. ABANDONMENT DEPOSIT

The Company is required under Province of Alberta Regulations to provide a cash deposit with the Alberta Energy and Utilities Board for the future abandonment of specific wells acquired as part of the Company's 1998 major oil and gas acquisition (See Note 4). The deposit is refundable on a per well basis upon notification of abandonment or reactivation of those specific wells. The deposit bears interest at Canadian chartered bank prime less approximately 2 percent.

4. PROPERTY AND EQUIPMENT

	1999		1998	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Petroleum and natural gas properties and related equipment	$20,099,161	$1,875,307	$20,034,595	$289,952
Furniture, equipment and other	25,567	3,621	–	–
	$20,124,728	$1,878,928	$20,034,595	$289,952

During 1998, the Company acquired petroleum and natural gas properties for total consideration of $20,790,516. The effective date for ninety five percent of these acquisitions was November 1, 1998.

Effective March 1, 1998, the Company acquired minor oil and gas properties. The purchase price was $700,000 and was paid by the Company to Comstate Resources Ltd. (Comstate), which at that time was a related party to the Company. The Company, due to the related party status, is required to record the oil and gas properties acquired at Comstate's carrying value, which was $221,000. The difference between the purchase price and the carrying value, net of future income taxes, has been charged directly against shareholders' equity.

5. LONG TERM DEBT

The Company has a long term bank revolving credit facility of $10,000,000 at December 31, 1999. The terms of the credit facility provide that the loan is due on demand and is subject to annual review. The credit facility has no fixed payment requirements. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Company's assets, and a general security agreement. The credit facility carries an interest rate of one-quarter percent above Canadian chartered bank prime.

At December 31, 1999, the Company owes $6,500,000 to Comstate. The loan is repayable upon demand but is subject to the current loan agreement with the Company's banker, which provides for repayment of the Comstate loan in amounts not to exceed cash flow of the Company provided that the Company maintains positive working capital together with unutilized amounts under the credit facility in excess of $1,000,000. Cash flow as well as working capital are to be determined in accordance with accounting principles generally accepted in Canada. The loan is unsecured, and bears interest at one half percent above Canadian chartered bank prime. The Company has engaged the services of Comstate to provide management and operational services on a fee basis for operating the Company's petroleum and natural gas properties.

Cash interest paid during 1999 for both of the above described loans was $1,168,495 (1998 - $225,605).

6. SHARE CAPITAL

Authorized

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

Issued	1999		1998	
	Number	Amount	Number	Amount
Common shares				
Balance, beginning of period	15,755,953	$3,077,729	5	$ 1
Common shares issued pursuant to Initial Public Offering	–	–	15,755,948	3,077,728
Exercise of stock options prior to stock split	18,000	3,600	–	–
Stock split	15,773,953	–	–	–
Exercise of stock options after stock split	41,000	4,100	–	–
Balance, end of year	31,588,906	$3,085,429	15,755,953	$3,077,729

On July 28, 1998, the Company completed its Initial Public Offering (IPO) by way of a Rights Offering. Total shares issued by the IPO were 15,755,948 for proceeds of $3,077,728. The proceeds are after share issue costs of $73,461, which is net of future income taxes of $60,105.

On July 26, 1999, the Company split its common stock by issuing an additional share for every outstanding share.

The Company provides a stock option plan for its service providers. Under the plan, the Company may grant options to its service providers for up to 4,423,000 shares of common stock. The exercise price of each option granted equals the market price of the Company's stock on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term.

A summary of the status of the Company's stock option plan as of December 31, 1999 and 1998, and changes during the years ending on those dates is presented below:

	1999		1998	
Fixed Options	**Shares**	**Weighted-Average Exercise Price**	**Shares**	**Weighted-Average Exercise Price**
Outstanding at beginning of year	1,434,000	$0.20	–	–
Granted prior to stock split	66,000	0.47	1,434,000	$0.20
Options exercised prior to stock split	(18,000)	0.20	–	–
Stock split	1,482,000	–	–	–
Granted after stock split	168,000	0.50	–	–
Options exercised after stock split	(41,000)	0.10	–	–
Outstanding at end of year	3,091,000	$0.13	1,434,000	$0.20
Options exercisable at end of year	1,003,000		–	

The following table summarizes information about fixed stock options outstanding at December 31, 1999:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Number Outstanding At 12/31/99**	**Weighted-Average Remaining Contractual Life**	**Weighted-Average Exercise Price**	**Number Exercisable At 12/31/99**	**Weighted-Average Exercise Price**
$0.10	2,791,000	3.4 years	$ 0.10	903,000	$ 0.10
0.225 to 0.50	300,000	3.4	0.38	100,000	0.38
$0.10 to 0.50	3,091,000	3.4 years	$ 0.13	1,003,000	$ 0.13

7. INCOME TAXES

The Company has recorded a future income tax asset (liability). The asset (liability) relates to the following temporary differences:

	1999 Amount	1998 Amount
Temporary differences related to assets and liabilities	$(356,721)	$(321,146)
Finance expense charged to shareholders' equity	53,691	37,793
Tax loss carry forward	135,367	655,186
	$(167,663)	$ 371,833

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

	1999	1998
Earnings (loss) before income taxes	$1,428,918	$(269,862)
Combined federal and provincial income tax rates	44.30%	45.00%
Income tax provision (recovery) calculated using statutory tax rates	633,011	(121,438)
Increase (decrease) in income taxes resulting from:		
Non-deductible crown royalties	478,499	43,330
Resource allowance	(592,643)	(33,119)
Other	20,950	4,307
Capital taxes	213,500	38,000
	$ 753,317	$ (68,920)

The Company paid $79,847 cash in taxes in 1999 (1998 - $0)

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

	Rate of Utilization %	Amount
Undepreciated capital costs	20-100	$ 2,774,312
Canadian oil and gas property expenses	10	13,476,436
Canadian development expenses	30	52,035
Canadian exploration expenses	100	197,492
Finance expenses	20	119,314
Tax loss carry forward	100	300,816
		$16,920,405

8. FINANCIAL INSTRUMENTS

The carrying value of the financial instruments of the Company approximates their estimated fair values. Financial instruments include accounts receivable, accounts payable and accrued liabilities, and current and long term debt.

9. COMMITMENTS

The Company entered into the following commodity hedging transactions in 1999 for a portion of its 2000 crude oil production:

Period of Agreement	Volume (barrels) per day	Price per barrel
January 1, 2000 to January 31, 2000	700	$31.00Cdn
February 1, 2000 to February 29, 2000	700	$30.50Cdn
March 1, 2000 to March 31, 2000	700	$29.95Cdn
April 1, 2000 to April 30, 2000	700	$29.65Cdn
May 1, 2000 to May 31, 2000	400	$22.05US

Corporate Information

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F. W. Woodward
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Officers

G. F. Fink - President
R. M. Jarock - Operations Manager and Vice President, Acquisitions
S. L. Safronovich - Vice President, Operations
G. E. Schultz - Vice President, Finance, and Secretary

Registrar and Transfer Agent

Olympia Trust Company
Calgary, Alberta

Auditors

Deloitte & Touche LLP
Calgary, Alberta

Solicitors

Parlee McLaws
Calgary, Alberta

Tupper, Jonsson & Yeadon
Vancouver, British Columbia

Bankers

The Royal Bank of Canada
Calgary, Alberta

Stock Listing

The Canadian Venture Exchange
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Trading Symbol: BON

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